

**REBUTTAL TESTIMONY OF**

**JAMES W. NEELY, P.E.**

**ON BEHALF OF**

**DOMINION ENERGY SOUTH CAROLINA, INC.**

**DOCKET NO. 2019-226-E**

**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.**

A. My name is James W. Neely and my business address is 220 Operation Way, Cayce, South Carolina. I am employed by Dominion Energy South Carolina, Inc. ("DESC" or the "Company") as a Senior Resource Planning Engineer.

**Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?**

A. I have.

**Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. The purpose of my rebuttal testimony is to respond in part to the direct testimony of Anthony Sandonato, Stephen Baron, Philip Hayet and Lane Kollen on behalf of the South Carolina Office of Regulatory Staff ("ORS"); Derek Stencklik on behalf of the Sierra Club; Kenneth Sercy on behalf of the South Carolina Solar Business Alliance ("SCSBA"); and David Hill and

1 Anna Sommer on behalf of the South Carolina Coastal Conservation League  
2 (“SCCCL”) and Southern Alliance for Clean Energy (“SACE”).

3 Generally, in their direct testimony, all of these parties offered  
4 critiques of the Company’s 2020 Integrated Resource Plan (“2020 IRP”) and  
5 modeling and recommendations for future IRPs. In this testimony, I will  
6 respond as appropriate. It will not be possible to respond to every item raised  
7 by the ORS and interveners. But I will address the ones that are of primary  
8 importance to my role in the IRP process.

9 **ORS RECOMMENDATIONS FOR THIS IRP**

10 **Q. WHAT IS YOUR RESPONSE TO THE REVIEW OF THE**  
11 **COMPANY’S IRP PRESENTED BY J. KENNEDY AND**  
12 **ASSOCIATES, INC. ON BEHALF OF ORS?**

13 A. In their “Review of Dominion Energy South Carolina, Inc. 2020  
14 Integrated Resource Plan” (the “ORS Report”), J. Kennedy and Associates,  
15 Inc. have done a thorough and competent job of reviewing the details of the  
16 IRP for compliance with the IRP statute. They have identified and pointed  
17 out potential improvements to the Company’s IRP plan and process in a  
18 useful and constructive way. While DESC does not believe that the original  
19 IRP was materially inaccurate, DESC generally agrees in adopting many of  
20 the recommendations that the ORS Report points out.

21 **Q. PLEASE EXPLAIN THE ACTIONS THAT DESC TOOK IN**

**RESPONSE TO THE REVIEW OF THE COMPANY'S IRP  
PRESENTED BY J. KENNEDY AND ASSOCIATES, INC. AND THE  
TESTIMONY OF OTHER PARTIES.**

A. DESC carefully reviewed each of the issues pointed out in the review of the Company's IRP presented by J. Kennedy and Associates, Inc. regarding the assumptions, modeling, and calculations used in the 2020 IRP. Specifically, DESC considered each of the points offered in the summary table presented in Mr. Sandonato's testimony, as compiled from ORS Report. The ORS Report indicated that certain of these changes should be addressed immediately, before the 2020 IRP could be approved. Many of these recommendations also overlapped with those set forth in the direct testimony of the Sierra Club, SCSBA, SCCCL and SACE, including recommendations related to reviewing the cost assumptions for solar, battery and gas turbine technologies and the suitability of including the effects of investment tax credits ("ITCs") as offsets to the capital cost of renewable resources.

In addition, the SCSBA's witness Kenneth Sercy, SCCCL/SACE witness Dr. David Hill, and Sierra Club witness Dr. Derek Stenclik testified that recent advances in battery technology and manufacturing costs indicated that the capital costs of battery storage used in the IRP modeling might be outdated. On further review, we determined that an adjustment was warranted and updated the costs.

1 As explained below, DESC has evaluated each of the 19 issues raised  
2 by ORS for implementation in this IRP cycle. DESC has reviewed the  
3 modeling assumptions that ORS questioned and revised them where  
4 warranted. It has corrected the errors or omissions the ORS Report pointed  
5 out. Where ORS recommended reevaluating items, we have done so. If no  
6 change was indicated based on those reevaluations, that is explained below.  
7 Where a recommendation appeared to be based on a misunderstanding or  
8 misinterpretation of the model or data, we have indicated that below as well.

9 Despite the short time frame with which to work, DESC was able to  
10 correct and implement all recommendations needing immediate  
11 implementation. Only one recommendation was not implemented, for the  
12 reasons discussed below. DESC reran its resource planning model and  
13 presents the results in a revised version of Chapter 5 of the 2020 IRP ("IRP  
14 Supplement"), Exhibit No. \_\_\_\_ (EHB-3) to Company witness Mr. Bell's  
15 rebuttal testimony.

16 **Q. PLEASE SUMMARIZE WHICH OF ORS'S RECOMMENDATIONS**  
17 **WERE INCORPORATED INTO THE IRP SUPPLEMENT.**

18 A. The table below summarizes which of ORS's recommendations were  
19 incorporated into the IRP Supplement. The item numbers correspond to  
20 those listed in Mr. Sandonato's testimony. The reasoning behind each  
21 response will be explained in more detail. The response to Mr. Sercy's

1 recommendation concerning the capital cost of battery storage is discussed  
 2 following ORS Item 15 below. Company Witness Eric Bell responds to the  
 3 recommendations related to the Wateree 2 analysis.  
 4

5 **Table A: Summary of Responses to ORS Recommendations**

Item	Recommendations for this IRP	Incorporated
11	The Company should update its Wateree 2 analysis by correcting errors and properly accounting for the insurance payout.	Bell Testimony
12	The Company should include a discussion of the Wateree 2 outage and the decision it makes to either repair or retire the unit.	Bell Testimony
13	The Company should review its assumptions regarding long-term continuing capital cost de-escalation of renewable energy projects	✓
14	The Company should review its capital cost assumptions for its internal combustion turbine (“ICT”) resource in this IRP to ensure that the costs are reasonable given its assumption appears to be much lower than other industry estimates.	✓
15	The Company should include fixed operation and maintenance (“O&M”) expenses for new owned solar and BESS resource additions in this and future IRPs.	✓
16	The Company should review its O&M assumptions for all combined cycle and ICT resource options and revise those assumptions in this IRP if they are found to be unreasonable or in error.	✓
21	The Company should escalate its cost assumptions for short-term winter capacity purchases.	✓
22	The Company should update its IRP to include tables that rank all RPs under all sensitivities.	✓

23a	The Company should correct errors in the transfer of PROSYM expenses to the Excel revenue requirement models.	✓
23b	The Company should include capitalized interest (“AFUDC”) in its revenue requirement modeling.	✓
23c	The Company should correct errors in calculations that escalated capital expenditures to future dollars for new resource additions and for Wateree and Williams Effluent Limitation Guidelines (“ELG”) capital expenditures/plant additions	✓
23d	The Company should include incremental capital expenditures/plant additions for existing resources and new resources after commercial operation, with the sole exception of the Wateree and Williams ELG capital expenditures/plant additions.	✓
23e	The Company should replace each new BESS resource after its assumed ten year operating life.	✓
23f	The Company should properly account for Investment Tax Credits for new owned solar and BESS resource additions.	✓
23g	The Company should include dismantlement costs, site restoration costs, and incremental transmission costs necessary for post-retirement voltage support for existing resources, particularly resources studied for possible early retirement.	No change indicated
23h	The Company should use the correct depreciable life assumption for ELG capital expenditures/plant additions.	✓
23i	The Company should include ICT natural gas firm transportation costs in any of the RPs.	✓
23j	The company should include the capital revenue requirements of the new ICT resource addition in 2040 in RP8.	✓
23k	The Company should review its escalation calculations for final ten (10) years of the study period as discussed in the Report.	✓

1 **Q. HOW DO YOU RESPOND TO ORS WITNESS SANDONATO'S**  
2 **TESTIMONY THAT THE COMPANY SHOULD REVIEW ITS**  
3 **ASSUMPTIONS REGARDING LONG-TERM CONTINUING**  
4 **CAPITAL COST DE-ESCALATION OF RENEWABLE ENERGY**  
5 **PROJECTS (ITEM 13)?**

6 A. The data used for determining the future cost of renewable energy  
7 projects was obtained from a widely-used industry source, the National  
8 Renewable Energy Laboratory ("NREL"). NREL annually documents a  
9 realistic and timely set of assumptions (*e.g.*, technology cost, fuel costs), and  
10 a diverse set of potential futures (standard scenarios) to inform electric sector  
11 analysis in the United States. This report is the 2019 Annual Technology  
12 Baseline Report, which we relied on for future cost of renewables. NREL  
13 provided this data in tabular form. Based on ORS's comments, we made  
14 further inquiry, and came to the conclusion that the data was provided in real  
15 dollars, not nominal dollars as expected. That fact was not stated in the NREL  
16 data. After converting the forecast to nominal dollars, we created two new  
17 escalation values for both solar and battery storage. The data showed that the  
18 escalation values could best be represented by using two different periods.  
19 One period represents the first ten years of the analysis; the second period  
20 represents the last twenty years. These new escalation values for solar and  
21 storage are as shown in the following table.

**Table B: Revised Escalation Values**

Technology	Escalation Years 2020-2030	Escalation Years 2031-2050
Solar PV	0.262%	0.756%
Battery Storage	-2.111%	-0.617%

As shown in the table, battery storage still de-escalates rapidly in the first ten years, but the cost declines level off, as ORS pointed out that would be expected. New capital costs schedules based on these escalation factors have been used in the revenue requirements calculations presented in the IRP Supplement. This change increased the cost of battery storage over the 40-year planning horizon, which, as ORS pointed out, was too deeply de-escalated in the original analysis.

**Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT THE COMPANY SHOULD REVIEW THE CAPITAL COST ASSUMPTIONS FOR ITS INTERNAL COMBUSTION TURBINE (“ICT”) RESOURCE IN THIS IRP GIVEN ITS ASSUMED COSTS APPEARS TO BE MUCH LOWER THAN OTHER INDUSTRY ESTIMATES (ITEM 14)?**

**A.** We reviewed all capital cost assumptions, which included discussions with Dominion Energy Services - Generation Construction Financial Management and Controls, as well as a review of other industry data. The ICT capital costs were confirmed to be appropriate. These costs are lower

1 than generically-reported turbine costs because of the volume discount  
2 Dominion Energy has negotiated with the vendor. These costs, however,  
3 represent the actual costs that DESC would expect to pay and are actual costs  
4 available to DESC in the market, not forecasts or projections.

5 **Q. HOW DO YOU RESPOND TO MR. STENCLIK'S**  
6 **RECOMMENDATION THAT THE COMPANY SHOULD USE**  
7 **ACTUAL BIDS TO DETERMINE THE PRICE OF GENERATION**  
8 **ASSETS?**

9 A. Actual bid information, where available, is contained in the data  
10 provided by Dominion Energy Services - Generation Construction Financial  
11 Management and Controls. Dominion Energy, Inc. has extensive utility  
12 operations and non-regulated renewable power subsidiaries. It is in the  
13 market regularly for both fossil and renewable generating assets. The  
14 information gathered from those markets, including actual bids, is reflected  
15 in the costs assumptions used in the IRP. But it would not be advisable for  
16 DESC to submit requests for proposals for generating assets that it did not  
17 intend to buy in the near term in order to create information for use in an IRP.  
18 Such requests would not generate serious bids on which the Company could  
19 rely and could prejudice the Company in the eyes of the market.

20 **Q. HOW DO YOU RESPOND TO MR. STENCLIK'S**  
21 **RECOMMENDATION THAT THE COMPANY SHOULD USE A**

1       **BLENDED CAPITAL COST FOR LARGE FRAME AND AERO-**  
2       **DERIVATIVE ICT?**

3       A.           It would not be appropriate to use a blended capital cost for ICT-Large  
4       Frame and ICT-Aero units. These are very different units with very different  
5       designs, operating characteristics and capital costs. Aero-derivative turbine  
6       generators are flexible in operation, more efficient and much more expensive  
7       per KW than their heavy frame counterparts. Heavy-frame ICTs are much  
8       less expensive to design and build, and have higher output per unit which  
9       leads to much lower capital costs per KW. A utility pays a substantial cost  
10      premium for the fast-start capability and favorable heat rate of ICT-Aero  
11      units. To treat them as having the same cost as ICT-Large Frame units would  
12      be a mistake.

13      **Q.    HOW DO YOU RESPOND TO SCSBA WITNESS KENNETH SERCY,**  
14      **SCCCL/SACE WITNESS DR. DAVID HILL, AND SIERRA CLUB**  
15      **WITNESS DR. DEREK STENCLIK'S RECOMMENDATION THAT**  
16      **THE COMPANY SHOULD REVIEW ITS CAPITAL COST**  
17      **ASSUMPTIONS FOR BATTERY STORAGE?**

18      A.           Based on ORS and interveners' testimony, we have reviewed and  
19      adjusted the capital cost assumptions related to battery storage. The value of  
20      \$1,911/kW used in the original calculations was provided by Dominion  
21      Energy Services - Generation Construction Financial Management and

1 Controls. Unlike other cost data provided by that group, this information was  
2 not based on actual projects or price commitments. A review of industry data  
3 indicated that \$1,349/kW would be a better estimate of current capital costs  
4 for battery storage. That value has been used in the analyses provided in the  
5 IRP Supplement.

6 **Q. HOW DO YOU RESPOND TO THE ORS'S RECOMMENDATION**  
7 **THAT THE COMPANY SHOULD INCLUDE FIXED OPERATION**  
8 **AND MAINTENANCE ("O&M") EXPENSES FOR NEW OWNED**  
9 **SOLAR AND BESS RESOURCE ADDITIONS IN THIS AND**  
10 **FUTURE IRPS (ITEM 15)?**

11 A. This is a valid observation. Adding O&M expense to the cost  
12 calculations for solar and BESS resources does improve the accuracy of the  
13 model. After reviewing several industry sources and discussing the issue with  
14 the Dominion Energy Renewables Department, we have identified the values  
15 provided by the 2020 Energy Information Administration Annual Energy  
16 Outlook ("EIA AEO") as the appropriate values to use for this purpose.  
17 These values are \$15.19/kW per year (2019 dollars) for solar and \$24.70/kW  
18 per year (2019 dollars) for battery storage. These costs have been included  
19 in the calculations as presented in the IRP Supplement.

20 **Q. HAS THE COMPANY COMPLIED WITH ORS'S**  
21 **RECOMMENDATION TO REVIEW ITS O&M ASSUMPTIONS FOR**

**ALL COMBINED CYCLE (“CC”) AND ICT RESOURCE OPTIONS  
AND REVISE THOSE ASSUMPTIONS IF THEY ARE FOUND TO  
BE UNREASONABLE OR IN ERROR (ITEM 16)?**

A. Yes. In response to the ORS’s recommendations, the Company reviewed its fixed and variable O&M assumptions for all combined cycle and ICT resources. This review found the values used for existing resources to be appropriate. However, the review showed that the certain assumptions concerning fixed and variable O&M for new ICT and new combined cycle resources should be revised. The revised values are shown in the table below.

**Table C: Revised O&M Values**

Resource	New Variable O&M (\$/MWh)	New Fixed O&M (\$/kW)
New CC	1.61	No change
New ICT 523	1.61	No change
New ICT 131	1.61	5.98

The new values have been included in the calculations presented in the IRP Supplement.

**Q. HAS DESC IMPLEMENTED THE RECOMMENDATION THAT  
DESC SHOULD ESCALATE ITS COST ASSUMPTIONS FOR  
SHORT-TERM WINTER CAPACITY PURCHASES (ITEM 21)?**

A. Yes. The Company reviewed its assumptions for short-term capacity purchases and added a 2% escalation factor to the monthly capacity charge used in the calculations reflected in the IRP Supplement. The variable energy

1 cost associated with these purchases already included a 2% escalation. This  
2 additional escalation factor has been included in the calculations as presented  
3 in the IRP Supplement. As testified to previously, incremental peaking  
4 reserves are modeled as short-term winter capacity purchases, although they  
5 may be met in a variety of ways such as demand response programs,  
6 upgrading existing peaking resources, or capacity purchases.

7 **Q. WHY WERE OFF-SYSTEM PURCHASES NOT MODELED AS A**  
8 **LONG TERM RESOURCE AND INCLUDED IN THE RESOURCE**  
9 **PLANS AS SUGGESTED BY WITNESS SERCY?**

10 A. There are several reasons that off-system purchases were not modeled  
11 as a long term resource. The first reason is that relying on large amounts of  
12 long-term off-system purchases creates a system reliability risk.  
13 Furthermore, as part of siting new generation assets, DESC will poll the  
14 market through requests for proposals to see if there is long-term capacity  
15 available at a better price. This information will be submitted to the  
16 Commission as part of the proceedings under the Utility Siting and  
17 Environmental Compatibility Act when authority to site a new unit is  
18 requested.

19 Another complicating factor is that good cost and availability  
20 information is not readily available for long term off-system purchases that  
21 will take place years in the future. In order to obtain good long term off-

1 system purchase information, we would need to release a genuine request for  
2 proposal. But to release such a request when no actual purchase was  
3 anticipated would not produce accurate pricing information, as mentioned  
4 above.

5 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
6 **THE COMPANY SHOULD UPDATE ITS IRP TO INCLUDE**  
7 **TABLES THAT RANK ALL RPS UNDER ALL SENSITIVITIES**  
8 **(ITEM 22)?**

9 A. The IRP Supplement now includes tables that present and rank each  
10 of the eight DESC resource plans against all three demand side management  
11 (“DSM”) cases, all three gas price cases and both CO<sub>2</sub> assumptions. Doing  
12 this increased the number of scenarios presented in the IRP plan from 64 to  
13 144. As a synopsis of the data, the IRP Supplement now provides a chart  
14 that shows the average ranking of each resource plan under each sensitivity  
15 and all sensitivities. For example, it shows that RP2 is the lowest costs  
16 alternative under all sensitivities with RP2 having an average score of 2.17,  
17 followed by RP3 with an average score of 2.22. RP2 is also the lowest costs  
18 alternative under all analyses that involve \$0/ton CO<sub>2</sub>, with an average score  
19 of 1.00. RP3 is the least cost alternative under all analyses that involve  
20 \$25/ton CO<sub>2</sub> with an average score of 1.22. RP7 is the least cost alternative

1 for all Medium DSM cases and under all analyses that involve High Gas  
2 cases.

3 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATIONS THAT**  
4 **THE COMPANY SHOULD CORRECT ERRORS IN THE**  
5 **TRANSFER OF PROSYM EXPENSES TO THE EXCEL REVENUE**  
6 **REQUIREMENT MODELS (ITEM 23A)?**

7 A. ORS identified two PROSYM errors. The first was double counting  
8 the cost of energy not served in all resource plans. The second error was the  
9 way firm fuel transportation costs at Cope station were handled in RP8,  
10 which was the only resource plan that involved Cope requiring firm gas  
11 transportation. The cost was overstated. The Company fixed these PROSYM  
12 transfer errors. Neither of these errors affected the ranking of the resource  
13 plans because the levelized NPV impact was small.

14 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
15 **THE COMPANY SHOULD INCLUDE CAPITALIZED INTEREST**  
16 **(“AFUDC”) IN ITS REVENUE REQUIREMENT MODELING (ITEM**  
17 **23B)?**

18 A. This was a valid critique and including AFUDC does improve the  
19 accuracy of the analysis. In response to ORS’s recommendation, the  
20 Company has included AFUDC in the capital cost of all new gas resources.  
21 The results have been included in the revised calculations as presented in the

1 IRP Supplement. Including AFUDC had the greatest impact on capital cost  
2 of CC 1-1 turbines, which increased by 5.7%. It had a similar percentage  
3 impact on the ICT Large Frame and Aero turbines.

4 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
5 **THE COMPANY SHOULD CORRECT ERRORS IN**  
6 **CALCULATIONS THAT ESCALATED CAPITAL EXPENDITURES**  
7 **TO FUTURE DOLLARS FOR NEW RESOURCE ADDITIONS AND**  
8 **FOR WATEREE AND WILLIAMS EFFLUENT LIMITATION**  
9 **GUIDELINES (“ELG”) CAPITAL EXPENDITURES/PLANT**  
10 **ADDITIONS (ITEM 23C)?**

11 A. The previous analysis assumed the ELG costs provided for Wateree  
12 and Williams were in 2026 dollars. Further review, in response to ORS’s  
13 comments, indicated that they were not. In the studies reported in the IRP  
14 Supplement, the ELG costs have been escalated to 2026 dollars, the year  
15 assumed for installation. The total ELG costs for the two units increased from  
16 \$228.5 million to \$255.2 million.

17 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
18 **THE COMPANY SHOULD INCLUDE INCREMENTAL CAPITAL**  
19 **EXPENDITURES/PLANT ADDITIONS FOR EXISTING**  
20 **RESOURCES AND NEW RESOURCES AFTER COMMERCIAL**  
21 **OPERATION, WITH THE SOLE EXCEPTION OF THE WATEREE**

1           **AND WILLIAMS ELG CAPITAL EXPENDITURES/PLANT**  
2           **ADDITIONS (ITEM 23D)?**

3       A.           ORS's observation is that even after the capital cost of a generating  
4           unit is paid, additional capital investments are required over the life of the  
5           unit to keep it working efficiently and reliability. It is appropriate to  
6           specifically include future capital costs as appropriate for each new resource  
7           and any retiring resource. Doing so improves the analysis. Incremental  
8           capital costs are included in the calculations presented in the IRP  
9           Supplement.

10      **Q.   HOW DO YOU RESPOND TO ORS'S RECOMMENDATION THAT**  
11           **THE COMPANY SHOULD REPLACE EACH NEW BESS**  
12           **RESOURCE AFTER ITS ASSUMED TEN YEAR OPERATING LIFE**  
13           **(ITEM 23E)?**

14      A.           In response to ORS's recommendation, DESC investigated this  
15           question and determined that battery storage can last up to 30 years but doing  
16           so requires a 20% cell augmentation every seven years. The fixed O&M cost  
17           that was added for battery storage (refer to Item 15) includes the cost for a  
18           3% cell augmentation every year. This allows the battery's capacity to be  
19           maintained so that replacement is not required during the model period.

20      **Q.   HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
21           **THE COMPANY SHOULD ACCOUNT FOR INVESTMENT TAX**

1           **CREDITS FOR NEWLY OWNED SOLAR AND BESS RESOURCE**  
2           **ADDITIONS (ITEM 23F)?**

3       A.           The Company adjusted the Modified Accelerated Cost Recovery  
4           System (“MACRS”) table used in the revenue requirements calculations to  
5           account for a 10% ITC for new owned solar and BESS resource additions.  
6           Ten percent is appropriate because no new owned solar and BESS resource  
7           additions occur before 2026. The value of a 10% investment tax credit has  
8           been included in the calculations presented in the IRP Supplement. After  
9           taxes, insurance, depreciation and return, the 10% ITC represents a small  
10          reduction in the fixed charge schedule for solar and BESS facilities.

11       **Q.   HOW DO YOU RESPOND TO MR. SERCY’S RECOMMENDATION**  
12       **THAT DESC SHOULD ASSUME A 22% ITC FOR SOLAR?**

13       A.           Under current law, 10% percent is the ITC rate that will apply to  
14           qualifying renewable facilities put in service in 2022 and beyond. Even with  
15           the option of a four-year safe harbor, 10% percent is appropriate rate to use  
16           in the IRP because no new owned solar and BESS resource additions will  
17           occur before 2026. For resource additions on or after 2026, the  
18           recommendation contained in Mr. Sercy’s testimony (p. 17)<sup>1</sup> on behalf of the  
19           SCSBA that the modeling should assume a 22% tax credit is not appropriate.

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<sup>1</sup> References to page numbers are to page numbers of that witness’s direct testimony.

1 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
2 **THE COMPANY SHOULD INCLUDE DISMANTLEMENT COSTS,**  
3 **SITE RESTORATION COSTS, AND INCREMENTAL**  
4 **TRANSMISSION COSTS NECESSARY FOR POST-RETIREMENT**  
5 **VOLTAGE SUPPORT FOR EXISTING RESOURCES,**  
6 **PARTICULARLY RESOURCES STUDIED FOR POSSIBLE EARLY**  
7 **RETIREMENT (ITEM 23G)?**

8 A. DESC considered this suggestion but made no change in the analysis  
9 because the Cost of Removal (“COR”) associated with an asset upon its  
10 retirement from service is included in the plant depreciation costs that are  
11 collected over the service life of the asset. When the asset is retired, the COR  
12 is charged against the depreciation reserve. No additional dismantlement  
13 costs are added because none has been identified at this time. Concerning  
14 incremental transmission costs, the cost of incremental transmission will  
15 vary depending on the location of the retired generation and the location of  
16 the new generation assets.

17 **Q. HOW DO YOU RESPOND TO MR. STENCLIK’S**  
18 **RECOMMENDATION THAT THE COMPANY SHOULD USE AN**  
19 **IDENTICAL TRANSMISSION COST FOR SOLAR AND GAS FIRED**  
20 **GENERATION (P. 6)?**

1 A. Using the same interconnection cost for solar and for gas and battery  
2 generation would not accurately reflect costs. In the case of battery storage,  
3 we agree and have modified the interconnection costs for battery storage.  
4 The interconnection cost for solar that is included in the model reflects the  
5 average historical cost incurred by solar projects on DESC's system. Solar  
6 farms have large footprints and are often located in rural areas where their  
7 size can be accommodated. The cost of connecting them to the grid reflects  
8 that fact. Gas fired generation as well as BESS units have compact footprints  
9 and can be located on sites where transmission capacity already exists, such  
10 as the sites of retired coal plants. DESC retains ownership of several suitable  
11 sites and assumes that if new gas fired generation units are built, they would  
12 be located on them.

13 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
14 **THE COMPANY SHOULD USE A DIFFERENT DEPRECIABLE**  
15 **LIFE ASSUMPTION FOR ELG CAPITAL EXPENDITURES/PLANT**  
16 **ADDITIONS (ITEM 23H)?**

17 A. The IRP originally depreciated the ELG according to the standard  
18 depreciable useful life of assets of that class. ORS correctly pointed out that  
19 the ELGs installed at Wateree and Williams will need to be removed from  
20 service when those plants are retired. The Company agrees and adjusted ELG  
21 fixed charge schedules to correspond with the retirement dates of those units.

1 This new cost schedule has been included in the recently updated revenue  
2 requirements calculations as presented in the IRP Supplement.

3 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
4 **THE COMPANY SHOULD INCLUDE ICT NATURAL GAS FIRM**  
5 **TRANSPORTATION COSTS IN ITS MODELS (ITEM 23I)?**

6 A. The Company has included additional firm transportation costs of  
7 \$22.13/dt-month for new ICTs in the IRP models, and these costs are shown  
8 as part of the results in the IRP Supplement. Historically, the Company has  
9 not held committed firm transportation for ICTs. However, in consideration  
10 of the size and capacity represented by the ITCs contained in these resource  
11 plans, the Company agrees that assuming the purchase of committed firm gas  
12 transportation for them is reasonable.

13 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
14 **THE COMPANY SHOULD INCLUDE THE CAPITAL REVENUE**  
15 **REQUIREMENTS OF THE NEW ICT RESOURCE ADDITION IN**  
16 **2040 IN RP8 (ITEM 23J)?**

17 A. Failing to include that cost was an error that the Company has  
18 corrected. It was a minor error that did not affect the conclusions of the  
19 analysis.

20 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATION THAT**  
21 **THE COMPANY SHOULD REVIEW ITS ESCALATION**

**CALCULATIONS FOR THE FINAL TEN YEARS OF THE STUDY  
PERIOD (ITEM 23K)?**

A. The Company has evaluated this recommendation and has changed the escalation calculations for the last ten years of the analysis period. The initial calculations used various escalation rates for the last ten-years of the analysis. This caused anomalies in the factors. The IRP Supplement uses two escalators for this period of the analysis—one for O&M costs and one for fuel-related costs. The table below describes these two escalators and how they are applied.

**Table D: Escalator Values**

Cost Type	Escalator 2050-2059
Fuel Costs	3%
Start Costs	3%
Variable O&M	3.41%
Fixed O&M	3.41%
SO <sub>2</sub> Costs	3%
NO <sub>x</sub> Costs	3%
CO <sub>2</sub> Costs	3%

The Fixed and Variable O&M escalator reflects the value used in the initial analysis for the last twenty years of the modeling period. The fuel-related escalator is the weighted average of fuel escalators for gas, coal and nuclear fuel as those escalators stood at the end of the modeling period.

**Q. HAVE ALL OF THE REVISIONS DISCUSSED ABOVE BEEN  
INCORPORATED INTO THE IRP SUPPLEMENT?**

1 A. Yes, all of the revisions discussed above have been incorporated into  
2 the modeling, with the results being shown in the IRP Supplement.

3 **Q. WHAT IS THE RESULT?**

4 A. Having made the requested changes, the overall conclusion of the plan  
5 has not changed. RP2 has the lowest overall cost to customers under base  
6 assumptions of \$0/ton CO<sub>2</sub>, medium DSM and base gas costs. RP2 is also  
7 the lowest cost resource plan in all scenarios where CO<sub>2</sub> is \$0/ton.

8 As an example of the results, Table E, below, summarizes the cost  
9 impacts of ORS's recommended changes as shown in the IRP Supplement  
10 for the Medium DSM, CO<sub>2</sub> cost of \$0/ton, and Base Gas scenario. The  
11 results are shown by percentage change from the 2020 IRP.

12

**Table E: Summary of the Cost Impacts of ORS Recommended Immediate Changes by Resource Plan**

(Shown by Percentage Change in the IRP Supplement from the 2020 IRP)

Resource Plan ID	Total	13,14, 23b,23c, 23e,23f, 23g,23h	15, 16b	16a, 23a	21	23d	23g	23i	23j	23k
RP1	16.81%	0.48%	0.24%	0.07%	0.01%	15.12%	0.00%	1.07%	0.00%	-0.18%
RP2	16.73%	0.35%	0.24%	-0.14%	0.05%	15.29%	0.00%	1.51%	0.00%	-0.57%
RP3	16.24%	0.56%	0.24%	0.17%	0.03%	13.93%	0.00%	1.48%	0.00%	-0.18%
RP4	16.59%	0.40%	0.28%	-0.14%	0.36%	14.84%	0.00%	1.45%	0.00%	-0.61%
RP5	17.53%	0.93%	0.89%	-0.14%	0.06%	14.90%	0.00%	0.97%	0.00%	-0.08%
RP6	17.24%	0.58%	0.69%	-0.13%	0.05%	15.11%	0.00%	1.49%	0.00%	-0.54%
RP7	17.36%	0.59%	0.49%	-0.13%	0.20%	15.22%	0.00%	1.35%	0.00%	-0.35%
RP8	18.52%	2.45%	1.57%	0.33%	0.26%	12.26%	0.00%	1.33%	0.45%	-0.13%
Average % Change	17.13%	0.79%	0.58%	-0.01%	0.13%	14.58%	0.00%	1.33%	0.06%	-0.33%
Max. Impact	2.29%	2.10%	1.34%	0.47%	0.35%	3.03%	0.00%	0.54%	0.45%	0.53%

Table E shows that the greatest effect of implementing the changes discussed on the relative costs of any two resources plans is by 2.29% which is the relative change in cost between the plan least affected (RP 3 – 16.24%) and the plan most effected (RP 8 – 18.52%).

Table F shows the same results, but in terms of monetary difference.

**Table F: Summary of the Cost Impacts of ORS Recommended Immediate Changes by Resource Plan**

(Shown by (\$000) Change in the IRP Supplement from the 2020 IRP)

Resource Plan ID	Total	13,14, 23b,23c, 23e,23f, 23g,23h	15, 16b	16a, 23a	21	23d	23g	23i	23j	23k
RP1	\$209,932	\$5,993	\$2,978	\$923	\$138	\$188,863	\$0	\$13,329	\$0	(\$2,292)
RP2	\$206,035	\$4,309	\$2,975	(\$1,741)	\$619	\$188,281	\$0	\$18,553	\$0	(\$6,962)
RP3	\$203,119	\$7,006	\$2,978	\$2,184	\$356	\$174,332	\$0	\$18,555	\$0	(\$2,292)
RP4	\$205,688	\$4,958	\$3,498	(\$1,693)	\$4,473	\$184,012	\$0	\$18,019	\$0	(\$7,579)
RP5	\$222,093	\$11,782	\$11,333	(\$1,721)	\$776	\$188,724	\$0	\$12,266	\$0	(\$1,067)
RP6	\$214,844	\$7,176	\$8,563	(\$1,619)	\$601	\$188,281	\$0	\$18,553	\$0	(\$6,711)
RP7	\$214,705	\$7,257	\$6,065	(\$1,656)	\$2,499	\$188,145	\$0	\$16,752	\$0	(\$4,357)
RP8	\$234,771	\$31,051	\$19,958	\$4,177	\$3,281	\$155,408	\$0	\$16,798	\$5,747	(\$1,649)
Average Change	\$213,898	\$9,942	\$7,294	(\$143)	\$1,593	\$182,006	\$0	\$16,603	\$718	(\$4,114)
Max Impact	\$31,652	\$26,742	\$16,984	\$5,918	\$4,335	\$33,455	\$0	\$6,289	\$5,747	\$6,511

As another example, Table G summarizes the cost impacts of ORS's recommended changes as shown in the IRP Supplement for the Medium DSM, CO<sub>2</sub> cost of \$25/ton, and Base Gas scenario. The results are shown by percentage change from the 2020 IRP.

**Table G: Summary of the Cost Impacts of ORS Recommended Immediate Changes by Resource Plan**  
**(Shown by Percentage Change in the IRP Supplement from the 2020 IRP)**

Resource Plan ID	Total	13,14, 23b,23c, 23e,23f, 23g,23h	15, 16b	16a, 23a	21	23d	23g	23i	23j	23k
RP1	14.54%	0.41%	0.20%	0.06%	0.04%	12.85%	0.00%	0.91%	0.00%	0.06%
RP2	14.31%	0.29%	0.20%	-0.10%	0.10%	12.88%	0.00%	1.27%	0.00%	-0.34%
RP3	14.18%	0.48%	0.20%	0.16%	0.07%	11.94%	0.00%	1.27%	0.00%	0.06%
RP4	14.41%	0.34%	0.24%	-0.09%	0.47%	12.52%	0.00%	1.23%	0.00%	-0.29%
RP5	15.49%	0.80%	0.77%	0.06%	0.11%	12.79%	0.00%	0.83%	0.00%	0.14%
RP6	14.92%	0.49%	0.58%	-0.10%	0.10%	12.84%	0.00%	1.27%	0.00%	-0.26%
RP7	15.02%	0.50%	0.42%	-0.10%	0.28%	12.92%	0.00%	1.15%	0.00%	-0.14%
RP8	16.53%	2.16%	1.39%	0.30%	0.36%	10.80%	0.00%	1.17%	0.40%	-0.06%
Average % Change	14.93%	0.68%	0.50%	0.02%	0.19%	12.44%	0.00%	1.14%	0.05%	-0.10%
Maximum Impact	2.34%	1.86%	1.18%	0.41%	0.43%	2.12%	0.00%	0.44%	0.40%	0.48%

Table G shows that that the greatest effect of implementing the changes discussed on the relative costs of any two resources plans is by 2.34% which is the relative change in cost between the plan least affected (RP 3 – 14.18%) and the plan most effected (RP 8 – 16.53%). Table H shows the same results, but in terms of monetary difference.

**Table H: Summary of the Cost Impacts of ORS Recommended Immediate Changes by Resource Plan**  
 (Shown by (\$000) Change in the IRP Supplement from the 2020 IRP)

Resource Plan ID	Total	13,14, 23b,23c, 23e,23f, 23g,23h	15, 16b	16a, 23a	21	23d	23g	23i	23j	23k
RP1	\$213,587	\$5,993	\$2,978	\$931	\$616	\$188,863	\$0	\$13,329	\$0	\$876
RP2	\$209,230	\$4,309	\$2,975	(\$1,466)	\$1,532	\$188,281	\$0	\$18,553	\$0	(\$4,954)
RP3	\$207,110	\$7,006	\$2,978	\$2,387	\$976	\$174,332	\$0	\$18,555	\$0	\$876
RP4	\$211,896	\$4,958	\$3,498	(\$1,335)	\$6,975	\$184,012	\$0	\$18,019	\$0	(\$4,230)
RP5	\$228,633	\$11,782	\$11,333	\$861	\$1,589	\$188,724	\$0	\$12,266	\$0	\$2,079
RP6	\$218,705	\$7,176	\$8,563	(\$1,462)	\$1,436	\$188,281	\$0	\$18,553	\$0	(\$3,843)
RP7	\$218,703	\$7,257	\$6,065	(\$1,477)	\$4,052	\$188,145	\$0	\$16,752	\$0	(\$2,090)
RP8	\$237,750	\$31,051	\$19,958	\$4,384	\$5,228	\$155,408	\$0	\$16,798	\$5,747	(\$824)
Average Change	\$218,202	\$9,942	\$7,294	\$353	\$2,800	\$182,006	\$0	\$16,603	\$718	(\$1,514)
Maximum Impact	\$30,640	\$26,742	\$16,984	\$5,860	\$6,359	\$33,455	\$0	\$6,289	\$5,747	\$7,032

The following key is used for all of the above tables:

**Table I: Numerical Changes Incorporated in IRP Supplement**

<b>ORS Report Item Number</b>	<b>Short Description of ORS Immediate Changes</b>
13	Revise the Escalation and De-Escalation Factors for Solar and Battery Costs
14	Review and Revise Capital Costs for Internal Combustion Turbines ("ICTs")
15	Review and Revise Fixed O&M for Solar and Battery Assets
16a	Review and Revise Variable O&M for Combined Cycle and ICTs
16b	Review and Revise Fixed O&M for Combined Cycle and ICTs
21	Escalate the Cost of Peaking Purchases (off-system sales and purchases)
23a	Correct Certain Identified Spread Sheet Errors
23b	Include AFUDC Costs in Fossil Unit Capital Costs
23c	Escalate Capital Cost of Coal Unit Effluent Limitation Guidelines ("ELG") Assets
23d	Add Ongoing Fossil Plant Capital Costs
23e	Revise End of Life/Life Extension Costs for Battery Storage ("BESS") Assets
23f	Include Investment Tax Credits in the Capital Cost of Solar and Battery Storage
23g	Review Retirement/Dismantlement Costs for Fossil Units
23h	Correct ELG Depreciation Assumptions
23i	Add Gas Firm Transportation Costs for Large ICT
23j	Include Costs of a ICT to Be Added in 2040 that Was Omitted in RP8
23k	Revise the Cost Escalation Assumption for Last 10 Years of the Studies

**Q. DO THE CONCLUSIONS IN THE IRP SUPPLEMENT CONCERNING THE LEAST COST PLAN WITH A \$25 PER TON CO<sub>2</sub> PRICE DIFFER FROM THE CONCLUSIONS IN THE 2020 IRP?**

**A.** Yes. RP8 remains the plan with the highest reduction in CO<sub>2</sub> emissions by a substantial margin in all scenarios. Modeling the plans with new assumptions makes RP3 the plan with the lowest levelized cost when all \$25/ton CO<sub>2</sub> cost scenarios are considered. RP7 is the least cost plan when a

1 CO<sub>2</sub> cost of \$25/ton, Medium DSM and High Gas is assumed. RP8 is the  
2 least cost plan when a CO<sub>2</sub> cost of \$25/ton, Medium DSM and Low Gas is  
3 assumed. As indicated in my direct testimony, in the initial study the  
4 levelized cost of the leading resource plans for each scenario were so closely  
5 bunched together that shifts in their ranking are to be expected as  
6 assumptions change and costs evolve. The IRP Supplement validates that  
7 point. Small changes have resulted in a reshuffling of the rankings of plans  
8 in the \$25/ton CO<sub>2</sub> cost scenarios, but the plans still remain closely aligned.

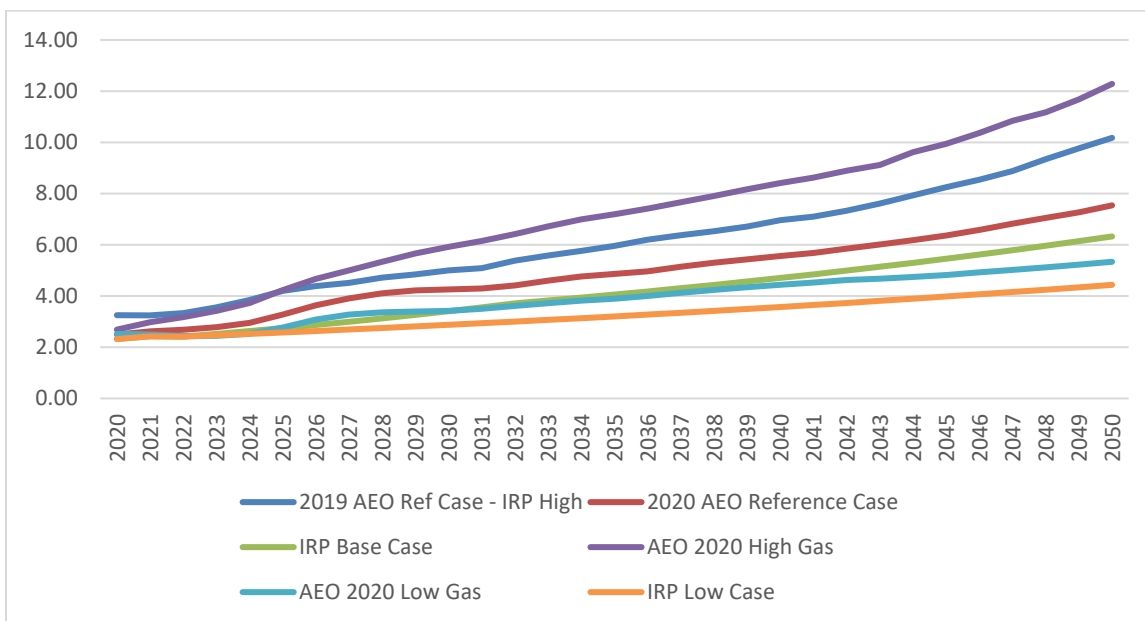
9 **OTHER ISSUES**

10 **Q. HOW DO YOU RESPOND TO MR. SERCY'S RECOMMENDATION**  
11 **THAT THE COMPANY UNDERSTATED NATURAL GAS PRICES**  
12 **BY USING PRICES THAT ARE IN "STARK CONTRAST" TO**  
13 **THOSE CONTAINED IN THE ENERGY INFORMATION**  
14 **ADMINISTRATION'S ANNUAL ENERGY OUTLOOK ("AEO")**  
15 **REPORT (PP. 26-28)?**

16 A. Mr. Sercy testifies in support of using the 2019 AEO gas prices  
17 forecasts and criticizes DESC for relying on gas price predictions that were  
18 substantially lower than those of the 2019 AEO report. The AEO 2020 report  
19 is now available and shows a lower price forecast. The AEO reference case  
20 has moved lower and is now located between the IRP Base Case and IRP  
21 High Gas Case and closer to the IRP Base Case than the IRP High Gas case.

As Company witness Mr. Bell testifies, the Company is planning to review its gas cost assumptions in future IRP updates. But the current range of gas price sensitivities is not unreasonable. The AEO 2020 reference case is shown in the graph below, along with IRP gas price forecasts.

**Graph A: Gas Price Predictions**



**Q. HOW DO YOU RESPOND TO MR. STENCLIK’S ALTERNATIVE RESOURCE SUPPLY PLAN MODELS?**

A. All other issues aside, and there are a number of issues that could be pointed out, Mr. Stenclik’s alternative resource plan models are simply unworkable. They assume that DESC can retire 1,294 MW of coal capacity and replace it with only 460 MW or 920 MW of battery storage and associated solar capacity. Mr. Stenclik says (p. 32) that he assumes that the capacity shortfall can be met through “existing gas resources, and limited

1 imports.” But there are no existing gas resources that are not already  
2 accounted for on the system. Imports of power from neighboring utilities  
3 cannot be relied upon to provide capacity during winter peak when  
4 neighboring utilities can be expected to be equally stressed. In addition, Mr.  
5 Stenclik treats short-term demand response capacity as a capacity that can be  
6 used year round to meet base capacity shortfalls, which is itself unreasonable.  
7 Demand response is a time-limited resource. Most critically, Mr. Stenclik’s  
8 model provides no capacity reserved to meet extreme winter peaks, which as  
9 Dr. Lynch testifies, will occur over time. The result of implementing Mr.  
10 Stenclik’s resource plans would be an unreliable electric system, particularly  
11 during times of extreme cold and peak winter demand.

12 **Q. HOW DO YOU RESPOND TO MS. SOMMER’S**  
13 **RECOMMENDATION THAT THE COMPANY INTENDS TO**  
14 **ACQUIRE 51 MW OF SOLAR GENERATION IN 2021 BUT DOES**  
15 **NOT SHOW HOW IT INTENDS TO DO SO (P. 16)?**

16 A. The 2020 IRP, at p. 26, indicates that solar capacity on DESC's system  
17 is expected to grow from 641 MW in February 2020 to 973 MW by  
18 December of 2020. The increase is due to solar projects being completed by  
19 third-party developers under existing power purchase agreement with DESC.

20 **Q. HOW DO YOU RESPOND TO MS. SOMMER’S**  
21 **RECOMMENDATION THAT THE IRP DOES NOT SPECIFY THE**

1       **PLANNING PERIOD USED AND THAT A “TYPICAL MODELED**  
2       **PLANNING PERIOD IS 20 YEARS, SOMETIMES AS LONG AS**  
3       **THIRTY YEARS” AND A “20 TO 30-YEAR NPV [NET PRESENT**  
4       **VALUE] WOULD BE VALUABLE?” (P. 17)**

5       A.           The IRP modeled the eight resource plans and calculated their NPV  
6       over 40 years. On pages 45, 46 and 48, it presented a chart of 40-year NPV  
7       for the eight resource plans under multiple sensitivity factors. The IRP states,  
8       at page 41, that the “base resources are the resources explicitly identified in  
9       the resource plan’s 40-year schedule to meet the summer or winter base  
10      reserve margin.” At page 44, it states that the planning model is used “to  
11      estimate total incremental revenue requirements over a 40-year planning  
12      horizon.” It states on page 45, “[t]he cost for each DSM case was calculated  
13      over a 40-year period . . . .” It states on page 49, “[t]he following table  
14      summarized the 40 year levelized NPV total fuel cost ranking for all eight  
15      resource plans . . . .” On page 65, it states that the model computes “estimated  
16      total revenue requirements over a 40-year planning horizon.”

17      **Q.   HOW   DO   YOU   RESPOND   TO   MS.   SOMMER’S**  
18      **RECOMMENDATION THAT DESC “BE REQUIRED TO INCLUDE**  
19      **SEVERAL YEARS OF RECENT GENERATOR PERFORMANCE**  
20      **DATA” AS WELL AS REPORTING OF “INDIVIDUAL EVENTS**  
21      **LIKE HURRICANE-RELATED OUTAGES?” (P. 19)**

1 A. These items are not a logical part of an IRP filing and are already  
2 widely available. Generator performance data is provided to the Commission  
3 every year in the fuel dockets. Additionally, whenever there has been a  
4 storm, the Company quickly provides the Commission with information  
5 about the storm and restoration efforts through ex parte briefings.

6 **ORS RECOMMENDATIONS FOR A FUTURE IRP**

7 **Q. HOW DOES THE COMPANY RESPOND TO THE**  
8 **RECOMMENDATIONS FOR FUTURE IRPs?**

9 A. ORS also made numerous recommendations for future IRPs. As Mr.  
10 Bell testifies, the Company will consider those recommendations, as well as  
11 all of the recommendations the other parties made for future IRPs, as  
12 appropriate.

13 Specifically, regarding implementing a least cost optimization  
14 expansion planning model, DESC is in the process of implementing the  
15 PLEXOS model. DESC is actively pursuing making this change and will  
16 keep ORS updated on its progress. Results using this model will be presented  
17 in a future IRP as soon as it can be implemented.

18 **CONCLUSION**

19 **Q. WHAT ACTION DO YOU REQUEST THAT THE COMMISSION**  
20 **TAKE IN RESPONSE TO YOUR REBUTTAL TESTIMONY?**

1     **A.**             I respectfully request that the Commission find that DESC has met its  
2             obligations under Act No. 62 and all relevant regulations.

3     **Q.     DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

4     **A.**             Yes. This concludes my rebuttal testimony.  
5